SECTION VI

Injection Well Construction and Operation

TexCom Gulf Disposal, LLC (TGD) is requesting permits to construct and operate four injection wells at its Facility in Montgomery County, Texas. One of the proposed wells was previously permitted by TCEQ as WDW-315. The permit expired prior to being purchased by TGD. The injection zone is the Cockfield formation at an approximate depth of 5,134 feet to 6,390 feet below ground. The proposed wells are and will be constructed in accordance with TAC §331.62 standards. The following sections describe the procedures that have been, or will be, followed to drill, sample, complete, and test each well prior to initiating injection operations. Additionally, procedures for plugging and abandoning each well are also provided along with specification of maximum instantaneous rate of injection, average rate of injection, and the total monthly and annual volumes requested.

The TGD WDW-315 well was drilled and completed as a commercial Class I non-hazardous disposal well by the original owners of the property. It was drilled and completed using the guidelines for a Class I disposal in accordance with TAC §331.62 standards. Throughout this application, references are made to the TGD WDW-315, utilizing actual well specifications, as well as the planned specifications for the other three wells. Unless specifically noted, completion work will be similar for all the wells.

VI.A Well Construction Information

VI.A.1 Well Depth

Proposed total drilling depth for each well is approximately 6,600 feet kelly bushing (KB). WDW-315 has a total depth of 6,578 feet KB. At total depth, the wells will penetrate the top of the Cockfield Shale which is the lower confining zone. Anticipated formations penetrated are described in detail in Section V (Geology and Hydrogeology) of this application.

VI.A.2 Well Casing Specifications

After drilling the WDW-315 surface hole to approximately 4,110 feet, 10 3/4-inch surface casing was set and cemented to surface with 2,590 sacks of cement. The protection casing hole was drilled to 6,578 feet and then 6,560 feet of 7 5/8-inch casing was run into the well. The casing was cemented to surface in two stages with 1,260 sacks. The injection well is completed with 4 1/2-inch tubing set on a packer at 5,108 feet. Casing specifications for WDW-315 and the other proposed wells are shown in Table VI-1. The casing strings are designed for a 30-year facility life.

TABLE VI-1
TexCom Class I Injection Wells Casing Program

Tubular	Depth (ft)	Size (in)	Weight (lb./ft)	Grade	Thread	Collapse/ Burst	Tensile Body/Joint (X 1000 lbs.)
Surface Casing	4,110	10.75	45.5	K-55	BTC	2,090/3,580	629/700
Protection Casing	6,560	7.625	26.4	P-110	LT&C	3,920/8,280	827/654
Injection Tubing	5,108	4.50	12.75	L-80	EU	7500/8430	--/--

VI.A.3 Well Completion and Completion Interval Information

The proposed injection zone is high quality sandstone with interbedded shale lenses. The proposed primary injection zone is from 5,134 feet to 6,390 feet in the Cockfield formation. The well completion is with an injection packer set inside casing. The injection interval is a perforated completion as detailed in Section VI.A.5 - Well Drilling Program.

VI.A.4 Well Construction Engineering Schematic

The well construction details for the TexCom WDW-315 are shown in Figure VI-I. Proposed wells 2, 3, and 4 construction details are shown in Figure VI-2. The schematics show casing information and setting depths, cement information, and completion details. Proposed wellhead information is shown in Figure VI-3 and the well annulus monitoring system (WAMS) is shown in Figure VI-4. The injection wellhead area will have secondary containment to collect and contain spills, leaks, and/ or storm water. All liquids collected in the secondary containment will be returned to the wastewater system for subsequent injection.

VI.A.5 Well Drilling Program

Injection well WDW-315 (Plant Well No. 1) was drilled and completed in 1999 by the former owners of the TGD facility. The following procedures describe the drilling operation which was used for WDW-315. The following general drilling and completion procedures are proposed to also be used for each of the three remaining injection wells at the TexCom Commercial Disposal Facility.

VI.A.5.a Drilling Procedures

Surface Hole

1. Drill mousehole and rathole

2. Mobilize drilling rig. Perform safety audits with plant safety personnel during rig-up to ensure that equipment setup complies with plant safety requirements.

3. Pick up 14 3/4 inch bit and the bottom hole assembly (BHA). Drill a 14 3/4 inch surface hole to + / - 4,111 feet using spud mud as detailed in the Drilling Fluids Program section

(VI.a.5.d) of this well plan. Take deviation surveys every 500 feet to assure that the maximum allowable deviation from vertical is 3 degrees, and maximum allowable deviation between surveys is 1 degree. After reaching surface casing setting depth, the drilling fluid will be circulated and conditioned to ensure correct fluid properties for the wireline logging procedure. The final deviation survey should be taken just before pulling out of the hole to run wireline electric logs.

Recommended **BHA** No.1
Bit- Bit Sub - 2 DC – Stabilizer – 2 DC - Jars - 4 DC- x/a

4. Rig up wireline equipment and run open-hole electric logs as listed in Section VI.A.6 - Well Logging, Coring and Testing Program.

   The wellbore will be conditioned as necessary to conduct this logging.

   Notify Texas Commission on Environmental Quality (TCEQ) of the cement job..

5. Run the bit and drilling assembly into the hole. Wash to surface casing setting depth. Circulate and condition the drilling fluid to ensure correct fluid properties for the casing running procedure.

6. Run 10 3/4-inch surface casing to + / - 4,110 feet. Refer to Section VI.A.2 - Well Casing Specifications for a detailed description of the casing and casing equipment.

   Reduce mud levels in surface circulating system and have additional handling capacity available to *recover any excess mud or cement that may be circulated* to *the surface.*

   TexCom field supervisory personnel will monitor drilling fluid during the cementing procedure.

7. Rig up cementing equipment and perform a pressure test on the lines. Circulate and condition the drilling fluid to ensure correct fluid properties for the cementing procedure. Reciprocate the casing continuously during the circulating of the drilling fluid.

8. Cement the casing in place. Details of the cement blends proposed are located in Section VI.A.8 - Well Construction Cementing Program.

   Be prepared to divert cement and cement contaminated drilling fluid returns away from circulating system and into appropriate containment. Retard the setting of the cement if necessary.

9. If no cement returns are observed at surface, contact wireline service provider and schedule a temperature survey to determine the top of the cement. Cement returns were observed at surface on the TexCom WDW-315.

10. Center the casing in the rotary table of the drilling rig after completing the cementing procedure and before the cement hardens.

11. Cement the annuIar space that does not contain cement. Fill the annulus space by pumping cement through small tubing that has been run into the annulus to the current top of cement.

12. After waiting on cement to harden for a minimum of 12 hours, cut off the surface and conductor pipe and install a 10 3/4-inch X 3,000-psi casing head. Perform a pressure test on the casing head after installation.

Protection Hole

13. Install blowout preventers (BOP) (Pipe-Blind-Annular) and auxiliary well control equipment. Perform a pressure test on the equipment to a low pressure of 250 and a high pressure of 2,000 psig.

    Test annular preventer to 70 percent of rated capacity.

14. Rig up wireline equipment and run a cement bond log tool inside surface casing to determine quality of the cementing procedure.

15. Rig down the wireline equipment.

16. Pick up a 9 7/8-inch bit and BHA and trip in the hole to the top of cement. Close pipe rams and perform a pressure test on the surface casing to 1,000 psig for 35 to 45 minutes. Record pressure on some type of recording device, preferably digital. The original copy of the pressure test record **MUST** be sent in to the office and made part of the well report to the state. Keep a copy of the pressure test record at the well site with other important records.

    Recommended **BHA** No.2
    Bit- Bit Sub - 2 DC – Stabilizer – 5 DC - x/a

17. Circulate new drilling fluid into well. Details of the drilling fluid characteristics are located in Section VI.A.5.d - Drilling Fluids Program of the well plan.

18. Drill out casing float equipment and 20 feet of new hole.

19. Perform a pressure test on the casing seat and formation leak off. However, do not exceed a 10.5 ppg equivalent drilling fluid density.

20. Drill a 9 7/8-inch hole from surface casing point to the first coring point at + / - 4,600 feet. Details of the coring program are located in Section VI.A.6 - Well Logging, Coring, and Testing.

21. Continue drilling from the first coring point to the second coring point at +/- 6,045 feet. Details of the coring program are located in Section VI.A.6 - Well Logging, Coring, and Testing.

22. Continue drilling from the second coring point to total depth (TD) with a 9 7/8-inch drilling bit.

23. Take inclination surveys every 500 feet to monitor the well path. Maximum allowable deviation from vertical is 5 degrees, and maximum allowable deviation between surveys is 2 degree.

24. Make short trips as hole conditions require.

    Notify TCEQ of the upcoming open-hole logging program in well #2

25. After reaching total depth, circulate and condition the drilling fluid to ensure correct fluid properties for the wireline logging procedure.

    Measure the drill string on the trip out to confirm well depths.

26. Rig up wireline equipment and run the electric logs and over the open-hole interval. Refer to Section VI.A.6 - Well Logging, Coring, and Testing for details.

27. After completing all wireline logging, pick up the drilling assembly and go into the hole with drill pipe to bottom. Check and note presence of fill at the bottom of the hole. Circulate hole clean, condition drilling fluid (if necessary).

28. Pull out of the hole with the drilling assembly.

    Notify TCEQ of upcoming cement job on well #2.

29. Rig up casing make-up and torque-turn measurement equipment. Run the 7 7/8-inch casing. Details of the casing program are located in Section VI.A.2 - Well Casing Specifications.

    Ensure that all dimensions of cementing equipment is *visually inspected, measured, and drifted before running in the hole.*

    API Modified thread lubricant will be used.

    Have a casing swedge available, on the rig floor, with circulating hoses ready, in the event the casing must be washed to bottom or in the event that well control procedures are required.

30. Once the casing is in position, rig up and circulate the hole for a minimum of 150 percent of the hole volume to clear the floats and cool the formation sufficiently for cementing. Add water and chemicals to the drilling fluid to adjust the characteristics of the fluid to improve mud removal from the annulus during the cementing procedure.

    Reduce mud levels in surface circulating system and have additional capacity on hand to recover any excess mud or cement that may be circulated to the surface.

    TexCom field supervisory personnel shall monitor drilling fluid at all times during the cementing procedure. An accurate accounting of volumes will be critical information in the event that circulation is lost.

31. Mix and pump the cement and spacer slurries. Details of the cementing program are located in Section VI.A.8 – Well Construction Cementing.

    Be prepared to divert cement and cement contaminated drilling fluid returns away from circulating system and into appropriate containment. Retard the setting of the cement if necessary.

    Reduce mud levels in surface circulating system and have additional tanks on hand to recover any excess mud or cement that may be circulated to the surface.

32. In the event cement returns are not observed at the surface, a temperature or similar diagnostic survey will be run to determine the top of cement.

33. Lift the BOP stack and hang off the 7 7/8-inch casing in tension. Weld on bell nipple, install casing cap and release drilling rig.

VI.A.5.b Completion Procedure

Casing and Cement Evaluation

34. Rig up service rig. Install BOP. Pick up a 6 3/4" bit on work string and trip into the hole.

35. Drill out DV tool and float collar. Drill to PBTD at 6,544 feet. Circulate well clean.

36. Run casing inspection log from TD to surface. Run GR sector CBL-CCL from TD to surface. Perform a pressure test on the casing to 1,750 psig for 30 - 45 minutes. Record the pressure test on a strip, circular, or digital recording device.

37. Run in hole with work string and circulate well with brine.

38. Pull out of the hole with pipe laying the work string down.

Perforated Completion

39. Rig up wireline perforating company.

40. Run in hole with perforating guns and perforate well as discussed in Section VI.A.9. Multiple runs will be required to perforate all the formation planned.

Formation Stimulation

41. Rig up coiled tubing unit to stimulate well.
42. Backflow well using nitrogen to clean up formation. Reciprocate tubing during stimulation.
43. Stimulate the perforated completion with acid through the coil tubing pumping all acid away into formation.
44. Rig down coil tubing unit.

Injection Tubing Installation

45. Pick up and run injection tubing and packer. Refer to Section VI.A.10 - Well Tubing Specifications for details.

46. Reverse circulate packer fluid containing appropriate corrosion inhibitor and oxygen scavenger additives in the annular space as detailed in Section VI.A.5.d Drilling Fluids Specification section.

    Notify TCEQ of the upcoming Mechanical Integrity Test and Bottom Hole Pressure Fall-off Test.

47. Set the packer at +/- 5,108 feet according to the packer manufacturer's setting procedure

48. Nipple down the blowout preventer equipment and nipple up the wellhead equipment. Perform pressure test on wellhead equipment as per manufacturer's recommendation.

49. Perform pressure test on tubing-casing annulus. Test pressure of 1,500 psi should be held for 30 to 45 minutes. Record the pressure test on a strip, circular, or digital recording device. The original copy of the pressure test record **MUST** be sent in to the office and made part of the well report to the state. Keep a copy of the pressure test record at the well site with other important records.

50. Leave well shut-in for 24 hours to allow wellbore temperature to stabilize.
51. Rig up logging equipment. Run static temperature survey from surface to total depth.
52. Rig up pumping equipment. Conduct radioactive tracer survey.
53. Run Bottom Hole Pressure Fall-off Test. Refer to Section VI.A.13- Injectivity Falloff Testing Program for details.
54. Complete rigging down equipment and cleaning site.
55. Project complete.

VI.A.5.c Drilling Contingencies

The drilling of WDW-315 encountered minimal problems while drilling. In the event that unforeseen events occur during drilling and completion of the additional three wells, detailed plans to remedy the specific problem will be developed, with input from all parties involved, including TCEQ, if applicable. These plans will then be implemented to solve the specific problem. The following are general contingency plans to address potential problem areas.

Lost Circulation

No zones of lost circulation have been identified by review of local offset data. Some fluid losses are anticipated during the drilling of the surface and protection hole as permeable sands are uncovered. These will be treated as necessary by the addition of sized lost circulation material during the drilling of the hole. Low mud weights and solids concentration in the drilling fluid will help minimize losses. Lost circulation pills will be spotted in the event that losses are excessive. Lost circulation material will be stored on location to allow quick response to any loss conditions

Overpressured Zones

Area review has indicated no overpressured zones in the local subsurface geology. During the drilling of the well, the following measures will be used to control/ contain formation pressure:

- Hydrostatic pressure exerted by drilling/ completion fluid
- Blowout prevention (BOP) equipment

Stuck Pipe

The possibility of stuck pipe exists due the possibility of differential sticking of the work string. Drilling jars will be used in the drilling of the protection hole to assist in freeing stuck pipe. Fluid loss control of the drilling fluid will be maintained to reduce the possibility of differential sticking of the work string. In the event that the work string becomes stuck in the hole, some or all of the following procedures may be utilized to free the pipe.

- Circulate a lubricating fluid in the well to assist in removal of the stuck pipe
- Rig up wireline and run a free point survey to determine the depth of the shallowest stuck point.
- Back off the section of free pipe using wireline detonation charges
- Engage the stuck portion of the work string with an overshot and fishing jars and attempt to jar the pipe free.
- Wash over the stuck pipe and remove it from the hole. Sidetrack the hole above the section of stuck pipe
- Agency notification and consent will be obtained before sidetrack operations are implemented.

VI.A.5.d Drilling Fluids Program

The drilling fluid program used for the drilling of WDW-315 is given below. All additional wells will use a similar drilling fluid program.

TABLE VI-2
Drilling Fluid Program

	Depth (Feet)	Mud Type	Weight (lb/gal)	Viscosity (Funnel/sec)	Fluid Loss (cc/30 min.)
Surface Casing Hole	0 - 4,111	Freshwater	8.6 - 9.0	35 - 45	No control
Protection Casing Hole	4,111 - 6,600	CLS/Lignite	8.6 - 9.6	35 - 45	No control

Notes:

1 Lost circulation material (LCM) will be on location to treat for fluid losses in shallow sands. The fluid system will be pre-treated with LCM before encountering any known or suspected loss zones.

2 High-viscosity sweeps will be used to assist hole cleaning.

Completion Fluid

Potassium chloride (KCl) was used as the completion fluid for WDW-315. The drilling fluid may be used as a completion fluid in the event that wellbore stability problems arise or are anticipated in the drilling of the remaining wells.

Annular Completion Fluid

The annular completion fluid for this well is a NaCl brine solution with corrosion inhibitor, biocide, and oxygen scavenger additives mixed into the annular completion fluid prior to pumping into the well.

VI.A.5.e Waste Fluid and Solids Management Planning

Prior to mobilizing equipment to the well location, the area beneath the drill rig footprint and surrounding area was graded and constructed in a manner to divert any collected liquids to the reserve pit.

Drilling mud that was circulated out of the hole will flow through solids control equipment consisting of a shale shaker to remove drill cuttings and other solids from the circulating mud system. All drill cuttings and removed solids were and will be contained and characterized for proper disposal according to applicable federal, state and city regulations.

VI.A.6 Well Logging, Coring, and Testing Program

VI.A.6.a Well Logging, Coring and Testing Program - Surface Hole

The following geophysical well logs were run in the open-hole section of the surface-casing hole for WDW-315.

- Spontaneous Potential
- Natural gamma ray
- Open-hole caliper
- Deep Resistivity
- Deep Focused Log
- Differential Caliper
- Integrated Hole Volume

The following cased hole geophysical well logs were run after cementing the surface casing in place in WDW-315.

- Gamma Ray
- Cement Bond with Variable Density Log
- Casing Collar Locator
- Temperature

These logs for both the open-hole and cased-hole portions of the surface casing hole will also be run during the drilling of wells 2, 3, and 4. Additional diagnostic logs may be run at the discretion of TGD personnel.

VI.A.6.b Well Logging, Coring, and Testing Program - Protection Casing Hole

The following geophysical well logs were run in the open-hole section of the protection casing (long string) hole during the drilling of WDW-315.

- Spontaneous Potential
- Natural Gamma Ray
- Density
- Resistivity
- Differential Caliper
- Neutron Porosity
- Fracture Finder
- Integrated Hole Volume

The following cased hole geophysical well logs were run after cementing the protection casing in place in WDW-315.

- Gamma Ray
- Cement Evaluation Log
- Cement Bond with Variable Density Log
- Differential Temperature Survey
- Casing Thickness
- Radioactive Tracer Survey

These logs for both the open-hole and cased-hole portions of the well will also be run during the drilling of wells 2, 3, and 4. Additional diagnostic logs may be run at the discretion of TGD personnel.

VI.A.6.c Well Logging, Coring, and Testing Program - Coring

The following cores were collected during the drilling of WDW-315. Subsequent wells will be cored in both the confining and injection zones as described in the drilling procedures section of this section.

TABLE VI-3
Conventional Coring Program

	Recovered Core Size	Depth	Formation/Lithology
Confining Zone	7-7/8” x 4" x 3 feet	4,600 – 4,603	Jackson Shale
Injection Zone	7-7/8” x 4" x 14 feet	6,070 – 6,084	Cockfield Formation

Supplemental conventional coring in the injection zone may be conducted to obtain additional reservoir data during the drilling of Wells 2, 3, or 4.

Core Analysis

Recovered cores were analyzed by OMNI Labs for the following:

- Core Gamma Ray (whole core only)
- Air Permeability
- Porosity
- Bulk Density
- Petrographic Analysis – X-Ray Diffraction, Thin Section Analysis, and Scanning Electron Microscope
- Compatibility Testing

Results of the core analysis are discussed in Section V of this application and copies of the analysis are located in the drilling and completion report located in Appendix 5. Cores recovered from the coring of wells 2, 3, and 4 will be analyzed for permeability, porosity, bulk density and other tests as needed for complete analysis of the formation.

VI.A.6.d Well Logging, Coring, and Testing Program - Formation Fluid Sampling

Formation fluid samples were collected from the injection interval in the Cockfield Formation and transported to WQS Laboratories for detailed analysis. The well was back-flowed using nitrogen and coil tubing during completion operations to recover fluid samples. The formation fluid showed to be high TDS brine typical of gulf coast oil producing intervals. Table VI-4 provides a summary of the analytical results.

TABLE VI-4
Formation Fluid Analysis

Parameter	Results (mg/l)
pH	7.07
Total Suspended Solids	278
Total Dissolved Solids	105,000
Chloride	62,000
Barium	83.5
Calcium	1,100
Sodium	30,900
Iron	36.4

A complete copy of the analysis is located in the drilling and completion report located in Appendix 5. Wells 2, 3, and 4 will also be backflowed and formation fluid samples collected prior to conducting any downhole injection testing.

VI.A.6.e Well Logging, Coring, and Testing Program - Mud-Logging Services

A mud-logging unit was rigged up during the drilling of the surface casing hole. The mug logging unit started logging at 3,500 feet and logged the well to total depth. The following services were provided:

- Drill Rate Curves
- Lithology
- Oil and Gas Content
- Chromotography
- 1" Log
- 10 foot Dry Samples (or as feasible based on rate of penetration)

Results of the mud logging analysis are located in the drilling and completion report located in Appendix 5.

VI.A.7 Well Casing Centralizer Information

Twenty-Six (26) hinged bow spring centralizers were used in setting the surface casing string. Centralizers were placed as follows:

- One centralizer 8 feet above the float shoe, straddling a stop collar
- One centralizer straddling the first casing collar above the float shoe
- Centralizers spaced evenly up to the DV tool.
- One centralizer just above the DV tool
- Evenly spaced from the DV tool to surface.

Twenty (20) hinged bow spring centralizers were used in setting the protection casing string. Centralizers were placed as follows:

- Centralizer 10 feet above the float collar, straddling a stop collar
- Centralizer every fourth joint, straddling a casing collar up to the surface casing
- Centralizer every 500 feet inside the surface casing to surface.

Wells 2, 3 and 4 will have centralizers placed on the casing following this same procedure and spacing.

VI.A.8 Well Construction Cementing Program

The cementing program for WDW-315 and each of the subsequent wells is designed to provide the best casing to formation bond possible while ensuring that the cement weight does not breakdown the formation during the pumping process. The cement blends are designed to be of sufficient weight and structural strength to prevent fluid movement outside the wellbore. The cement blend for the cement across the injection zone will not breakdown in the presence of the injected fluids planned for the injection well. The injection fluids do not contain chemicals which are detrimental to Class H premium cement and therefore no special cement blend or cement additives are required for the injection well.

VI.A.8.a Surface Casing Cement Specifics

The following cementing program was implemented for installation of the surface casing string:

- 10 ¾-inch casing in 14 ¾-inch hole at 4,125 feet
- DV tool at 1,801 feet
- Down jet float shoe
- Stab in float collar
- Cement returns to surface
- Actual volume was calculated from caliper log plus 20 percent excess

TABLE VI-5
Surface Casing Cement Specifics

	Cement Type	Weight (lb/gal)	Yield (cu ft/sack)	Quantity (sack)	Volume (cu ft)
FIRST STAGE					
Lead Cement	Trinity Light	12.50	1.54	750	1,155
Tail Cement	Premium	16.20	1.09	530	578
SECOND STAGE					
Lead Cement	Trinity Light	12.70	1.45	980	1,421
Tail Cement	Premium	16.20	1.09	330	360

Proposed wells 2, 3 and 4 will use a similar cementing program. A cementing recommendation is attached for the three proposed injection wells.

VI.A.8.b Protection Casing Cement Specifics

The following cementing program was implemented during installation of the protection casing string:

- 7 5/8-inch casing in 9 7/8-inch hole at 6,578 feet
- DV tool at 4,242 feet
- Down jet float shoe
- Float collar
- Cement returns to surface
- Actual volume was calculated from caliper log plus 20 percent excess

TABLE VI-6
Protection Casing Cement Specifics

	Cement Type	Weight (lb/gal)	Yield (cu ft/sack)	Quantity (sack)	Volume (cu ft)
FIRST STAGE Lead Cement	Trinity Light	12.40	1.54	225	346
Tail Cement	Premium	16.40	1.06	245	260
SECOND STAGE Lead Cement	Trinity Light	12.40	1.54	540	832
Tail Cement	Premium	16.40	1.06	250	265

Proposed wells 2, 3 and 4 will use a similar cementing program. A cementing recommendation is attached for the three proposed injection wells.

VI.A.9 Well Tubing Specifications

WDW-315 is completed with 4 1/2-inch injection tubing set within the 7 5/8-inch protection casing string. Injection tubing specifications for WDW-315 and the proposed wells are shown in Table VI-2. The tubing strings are designed for a 30-year facility life.

TABLE VI-7
Injection Tubing Specifications

Tubular	Depth (ft)	Size (in)	Weight (Ib./ft)	Grade	Thread	Collapse/ Burst (psi)
Injection Tubing	0 – 5,108	4 1/2	12.75	L-80	EU	7500/8430

VI.A.11 Well Packer Information

The well packer is in WDW-315 is set just above the Upper Cockfield formation at a depth of 5,108 feet. The proposed wells will be completed in a similar fashion. The packer in WDW-315 is a Baker Model FAB-1 retainer production packer. The packer is designed for a 30-year facility life. The proposed wells will have similar equipment.

VI.A.12 Well Perforations

WDW-315 was perforated in the lower portion of the Lower Cockfield. The well was perforated in various sand intervals from 6,184 – 6,372 feet. There is a total of 100 feet of formation that was perforated at 2-shots per foot. Initial testing of the perforated interval has shown that the formation permeability is lower than expected and as a result, TGD will be perforating an additional 45 feet of the Lower Cockfield once the injection permit is approved. There is 145 feet of clean sand located in the Lower Cockfield zone. TGD will be adding perforations across all the available clean sand in the zone. The existing 100 feet of perforations will be re-perforated at 4-shots per foot and the 45 feet of new perforations will be perforated at 6 shots per foot. The perforated interval will be from 6,045 to 6,390 feet.

Wells 2, 3 and 4 will be perforated across the injection interval from 6,045 to 6,390 feet.

VI.A.13 Well Stimulation Program

WDW-315 was stimulated after drilling by backflowing the well with coil tubing and nitrogen. Laboratory testing of the formation core sample indicated that there was a potential for damaging the formation if an HCl based mud acid was used to clean up drilling mud contamination. The purpose of treating the well after drilling is to remove formation skin damage due to invasion of solids during the course of drilling and open flow channels for the injected effluent. The use of nitrogen to backflow the well help clean up mud contamination issues but can reduce the injectivity in a new injection well due to formation fines being pulled into the pore spaces near the wellbore.

One the TGD permit is approved and the well is re-perforated, the well will be treated with a citric acid or some specialty blend of acid which is recommended by one of the companies which specialize in acid treatment. Details on the acid treatment plan will be provided in the notification to the TCEQ for well work activities. Once a suitable treatment program is designed, this program will be followed in the subsequent wells.

VI.A.14 Injectivity/Falloff Testing Program

Reservoir testing to determine well capacity and reservoir characteristics was conducted after drilling and completing WDW-315. The test was completed using native brine and local brine water. The test was conducted as follows:

1. Rig up wireline equipment (bottom-hole pressure gauge with surface read-out) and run a static bottom-hole pressure survey.
2. Injection was initiated at 3 barrels per minute for 12 hours. The pressure was monitored at surface.
3. The well was then shut in and allowed to fall off for 32 hours following injection.
4. The tools were then pulled from the well and the data submitted to Mr. Peter Stan at Fairchild, Ancell, and Wells for analysis.

TABLE VI-7
Injection Fall Off Test Results

Parameter	Results
Injection Rate	4,320 bpd (3 bpm)
Net Thickness	100
Porosity	31%
Static Reservoir Pressure	2,502 (prior to injection)
Gauge Depth	6,200 ft.
Skin Factor	5.92
Permeability	80.9 md

The results of the fall off test resulted in lower permeability than was expected in WDW-315. When compared to the core testing and area information, the 80.9 md permeability seems to be an anomaly likely based on the high shale content of the portion of the Cockfield perforated. Once TGD receives their permit for operation the well will be re-perforated in more favorable portions of the injection zone as described in Section VI-A.12. The results of the injection fall off testing and a copy of the fall off pressure data are located in Appendix5.

The proposed wells 2, 3, and 4 will be tested in a similar fashion. The initial running of the tools will collect the bottom hole pressure, bottom hole temperature, and the static fluid level prior to initiating injection into the well.

VI.B Renewal Permit and Amended Permit Information

Although this well was previously permitted, the permit expired without ever being operated as a Class I injection well. No surface facilities have been built and the well has sat idle for over 5 years. Therefore, TGD is submitting all information as if this was a new well and the information required in this section is supplied within the submitted information.

VI.C Injection Well Operation

VI.C.1 Anticipated Operational Life of the Well

The TGD injection well equipment is designed for 30 years of operation. Routine maintenance and periodic testing as required by TCEQ will ensure its proper operation during the expected lifetime. In addition, reservoir modeling (Section VII) conducted using the well parameters indicates a minimal increase in injection pressure over the 30 year life of the well.

VI.C.2 Maximum Instantaneous Rate of Injection

TGD anticipates that maximum daily flow to the injection well system will be 504,000 gallons per day (350 gpm) at full facility production. TGD is requesting that the instantaneous rate of injection be set at **350 gpm** (rate is based on modeling presented in Section VII- Reservoir Mechanics) for each well with the limitation of a facility maximum of 350 gpm. This will allow TGD to adjust flow to the well system to maximize the efficiency of the injection wells.

VI.C.3 Average Rate of Injection, Total Monthly, and Annual Volumes

TGD anticipates that maximum daily flow to each injection well will be 504,000 gallons (350 gpm) at full facility production. TGD is requesting that the cumulative annual site volume be calculated at 350 gpm and limited to 183,960,000 gallons (volumes based on modeling presented in Section VII - Reservoir Mechanics):

TGD has provided detailed modeling in Section VII- Reservoir Mechanics in support of this request.

VI.C.4 Maximum Surface Injection Pressure

TGD requests that the permitted surface injection pressures be set at 1,250 psi for the Cockfield injection interval. Calculation of the Maximum Surface Injection Pressure is contained in Section VII.A.5. Maximum allowable surface injection pressure for wells 2, 3, and 4 will be modified to reflect any differences in tubular design and resulting friction losses as outlined in Section VII.A.5.

VI.C.5 Range in Injection Rate and Surface Injection Pressure and Annual Volume

TGD anticipates that average daily flow to the injection well field will be a maximum of 504,000 gallons per day at normal facility operation. The daily flow will fluctuate depending on the number of deliveries to the facility each day. Surface injection pressure for the injection wells is anticipated to range between 0 psi and 1,250 psi at normal plant operation, based on a reasonable estimate of well skin.

VI.C.5 Well Maintenance and Operation

TGD will operate the wells in compliance with provisions specified or referenced in the final injection permits. The wells and surface facilities will be maintained in good working order and painted, if appropriate. All-weather roads will be installed to allow access to each injection well and associated facilities, and maintained in good condition. Each well will be clearly identified by a posted sign containing the company name, company well number, and commission permit number (lettering will be at least l-inch high).

Pressure gauges will be installed at the wellhead on the injection tubing and the on the annulus between the injection tubing and the long-string casing and maintained in good working order at all times. Continuous recording devices will be installed to record at a minimum:

a. injection tubing pressures;
b. injection flow rates;
c. injection fluid temperatures;

d. injection volumes;
e. tubing -long-string casing annulus pressure; and
f. tubing -long-string casing annulus volume.

All gauges, pressure sensing devices, and recording devices will be tested and calibrated quarterly. Test and calibration records will be maintained at the facility. All instruments will be housed in weatherproof enclosures.

Automatic alarm and automatic shutoff systems will be designed and installed to sound in the event that pressures, flow rates, or other parameters designated by the Executive Director exceed a range or gradient specified in the injection permit. When a qualified/ trained operator is not on location the automatic alarm and automatic shutoff systems will be designed and installed to sound and shut-in the well. If an alarm or shutdown is triggered, TGD will immediately investigate and as expeditiously as possible identify the cause of the alarm or shutoff. If, upon investigation, the subject well appears to lack mechanical integrity, TGD will:

1. Immediately cease injection of effluent unless continued or resumed injection is authorized by the Executive Director.
2. Take all steps necessary to determine the presence or absence of a leak.

If a loss of mechanical integrity is discovered during the investigation (or during annual mechanical integrity testing), TGD will:

1. Immediately cease injection of effluent.
2. Take reasonable steps necessary to determine if there has been a release of effluent into any unauthorized zone.
3. Notify the Executive Director within 24 hours after the loss of mechanical integrity is discovered.
4. Notify the Executive Director when injection can be expected to resume.
5. Restore and demonstrate mechanical integrity to the satisfaction of the Executive Director prior to resuming injection of effluent covered by this permit.

If there is evidence that there has been a release to an unauthorized zone due to loss of mechanical integrity as described above (well has already been shut in), TGD will:

1. Notify the Executive Director within 24 hours of obtaining such evidence.
2. Take the necessary steps to identify and characterize the extent of any release.
3. Propose a remediation plan for Executive Director review and approval. Comply with any remediation plan specified by the Executive Director.

4. Implement with any remediation plan specified by the Executive Director.
5. Notify the local health authority, place a notice in a newspaper of general circulation, and send notification by mail to adjacent landowners where such a release is into a USDW or freshwater aquifer currently serving as a water supply.

VI.D Waste Compatibility and Corrosion Monitoring

VI.D.1 Waste Compatibility

To protect Underground Sources of Drinking Water (USDW), injection wells must not allow fluids to escape into unauthorized zones. Any escape of fluids may cause contamination of a USDW, directly or indirectly, by forcing lower-quality fluids to move into these zones. If a well protects the USDW by not allowing fluids to escape or migrate, it is said to have mechanical integrity. The well materials must also be compatible with annular fluids, formation fluids, soil, and other elements of the well's environment.

EPA conducted an inventory of Class I waste wells in the United States. The data collected have provided a database for determining the composition of the most generally injected waste fluids. For most Class I injection wells, pH neutralizers, cathodic, and protective coatings are probably the most effective methods for preventing corrosion.

The effluent stream proposed for injection (see Section IX- Wastes and Waste Management) is mostly water with a few dissolved metals and organics present in low concentrations. Anticipated pH of the effluent is within the neutral range and is only mildly corrosive to carbon steel. Therefore, carbon steel is an appropriate material for construction of these wells.

The TexCom Facility has not been built and the final composition of the waste stream can not be determined until the facility is built and clients for disposal are put under contract. Therefore, there is no compatibility testing that can be conducted in the material of construction at this time. As discussed in the preceding paragraph, the waste stream will be kept in a condition as to reduce the corrosive nature of the fluids on the wells construction materials.

VI.D.2 Corrosion Monitoring

There are five commonly used methods to detect and measure corrosion. The most common is the use of weight-loss coupons. By inserting a sample of the material with a known weight into the injection stream for a defined period of time, corrosion rates may be determined.

Other methods include the use of corrosion loops, which are smaller-diameter pipes installed parallel to the injection tubing, which may be valved off and removed for inspection. Electrical resistance probes that measure changes in the resistance of a metal as it corrodes, polarization resistance probes, caliper surveys, and other well logging methods may also be used for corrosion detection and measurement.

Corrosion monitoring of well materials will be conducted quarterly. Corrosion monitoring will be conducted using weight-loss coupons. Test materials will be constructed of the same material as used in the wellhead, injection tubing, packer and protection casing. The test materials will be exposed continuously to the effluent fluids with the exception of when the well is taken out of service.

VI.E Well Closure and Post-Closure Care Plans

TexCom will provide the required financial assurance information for closure and post- closure care in Attachment F of this Permit Application document. Well closure procedures and post-closure care plans are detailed in the following subsections.

VI.E.1 Injection Well Closure Plan

The closure procedure for the TexCom wells is designed to be used if the effluent disposal well operations are abandoned or if a well has reached the end of its useful life. The procedure for well closure is described below and may be modified according to the direction of the TCEQ. Figure VI-4 is a schematic of the proposed well closure design.

1. The plant shall notify the TCEQ of intent to plug at least 60 days prior to closure. The following information will be provided:
   - Type and number of plugs
   - Placement of each plug, including the elevation of both the top and bottom of the plug
   - Type, grade, and quantity of the plugging material and additives to be used
   - Method used to place plugs in hole
   - Procedure used to plug and abandon the well
   - Any information on newly constructed or discovered wells, or additional well data, within the Area of Review
2. Plugging operations will be conducted as follows:
   - Record bottom hole pressure in the injection zone for a time specified by the TCEQ
   - Conduct an annulus pressure test at 1,000 psi for 30 minutes.
   - Conduct Radioactive Tracer Survey
   - Prepare location for workover rig
   - Move workover rig onto location
   - Remove wellhead and nipple up blow our preventers. Kill well with drilling fluid
   - Remove injection tubing

- Run in hole with cement retainer and set above existing packer.
- Sting into packer with workstring and pump 120 sacks premium cement below cement retainer.
- Place 100 foot balanced cement plugs at
    1. on top of cement retainer
    2. across the 7-inch DV tool at 4,242 feet
    3. across the base of the surface casing at 4,110 foot.
    4. at the top of the well.
    5. Tag all cement plugs after cement has hardened
- Top of final cement plug should be within 25 feet to surface.
- Pressure test each plug to 1,000 psi for 30 minutes.
- Top of well with cement to within 5 feet of surface.
- Cut off casing three feet below ground surface and weld steel plate on top
- Inscribe on plate the injection well permit number, date of abandonment and company name.
- A permanent marker will be erected at the well site. The marker will contain all pertinent well information.

3. A plugging report will be filed with the Executive Director within 30 days alter completion of plugging.

VI.E.1.a Estimated Plugging Cost

An amount of $76,400 to cover the plugging and securing of each well was calculated assuming the balance method was used to spot cement plugs. The mechanical integrity of the wells will be determined by pressure testing during abandonment. The estimated cost of this is also included in the bond calculations. These tests will be used to determine whether remedial cement squeeze operations will be necessary prior to plugging the well(s). The cost estimate for well plugging is provided below. The estimated cost of well closure for each well is $76,400. These costs are covered under the financial assurance section (Section IV and Attachment F).

WELL CLOSURE COST ESTIMATE

COMPLETION - INTANGIBLE COSTS:	COST
Cement & Cementing Services	$6,000
Dirtwork, Roads, and Location	25,000

Completion Unit:	8	days @	$ 3,125	25,000
Water Hauling & Completion Fluids				3,500
Cased Hole Wireline Services				6,500
Transportation				5,000
Engineering & Supervision				10,000
Permits and Permanent Damages				200
Risk Management				500
Miscellaneous Contingency				2,700
Christmas Tree & Wellhead				(1,000)
Production Tubing				(7,000)
			Total Closure Cost	**$76,400**

VI.E.2 Post-Closure Plan

This post-closure plan has been developed for the TexCom Facility in accordance with 31 TAC 331.68. Upon closure of the injection wells, TexCom will submit a survey plat to the local zoning authority that shall indicate the location of the injection wells relative to permanently surveyed benchmarks. The facility will also submit a copy of the plat to the TCEQ Underground Injection Control Unit in Austin, Texas. TexCom will also notify the Texas Railroad Commission and provide information necessary to impose appropriate conditions on subsequent drilling activities that may penetrate the well's confining or injection zone.

TexCom will retain for a period of five years following plugging and abandonment, records reflecting the nature, composition and volume of all injected fluids.

TexCom will place a monument or permanent marker to identify the plugged well prior to abandonment. This marker will state the permit number, date of abandonment, and company name.

References

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